State of Idaho
Department of Environmental Quality
Air Quality Division

AIR QUALITY PERMIT
STATEMENT OF BASIS

Permit to Construct No. P-2008.0114

Facility Review

Glanbia Foods, Inc.

Glanbia Foods/Gooding Facility

Gooding, Idaho

Facility ID No. 047-00008

October 9, 2008

Darrin Pampaian

Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

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Acronyms, Units, and Chemical Nomenclature

acfm	actual cubic feet per minute
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
ASTM	American Society for Testing and Materials
biogas	any gas fuel derived from the decay of organic matter, as the mixture of methane and carbon dioxide produced by the bacterial decomposition of sewage, manure, garbage, or plant crop
Btu	British thermal unit
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
gr	grain (1 lb = 7,000 grains)
dscf	dry standard cubic feet
EPA	U.S. Environmental Protection Agency
H_2S	hydrogen sulfide
HAP	Hazardous Air Pollutant
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
lb/hr	pounds per hour
m	meter(s)
MACT	Maximum Achievable Control Technology
$\mu g/m^3$	micrograms per cubic meter
MMBtu	million British thermal units
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
Rules	Rules for the Control of Air Pollution in Idaho
scf	standard cubic feet
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SM	Synthetic Minor
SO_2	sulfur dioxide
SO_x	sulfur oxides
TAP	Toxic Air Pollutant
T2	Tier II operating permit
T2/PTC	Tier II operating permit and permit to construct
T/yr	tons per year
UTM	Universal Transverse Mercator
VOC	volatile organic compound
WPC	whey protein concentrate
wt %	weight percent

1. FACILITY INFORMATION

1.1 Facility Description

Glanbia Foods, Inc. (Glanbia) operates a cheese and whey manufacturing facility located at 1728 South 2300 East, Gooding, Idaho. The facility covers approximately 500 acres of land located about 3.7 miles east of the city of Gooding. The facility currently has the following pieces of permitted equipment: An anaerobic digester, a flare, four full-time boilers (Boiler No. 1, Boiler No. 2, Boiler No. 3, and Boiler No. 4), an auxiliary boiler (Boiler No. 5), a lactose production line including a lactose dryer and a lactose receiving baghouse, and a whey protein concentrate bagging line.

1.2 Permitting Action and Facility Permitting History

This PTC is a modification of existing PTC P-2008.0065 at an existing facility.

The following information was derived from a review of the permit files available to DEQ. Permit status is noted as active and in effect (A) or superseded (S).

June 26, 2008	PTC permit P-2008.0065 was issued which superseded PTC permit P-2007.0052 (A). This project was to increase production on the lactose production line.
August 22, 2007	PTC permit P-2007.0052 was issued which superseded PTC permit P-060454 (S). This project was to increase production on the lactose production line.
March 23, 2007	PTC permit P-060454 was issued (S) which superseded PTC permit P-040404. This project was to remove the Continental boiler and install a new Cleaver-Brooks boiler (that was exempt from permitting).
September 6, 2005	PTC permit P-040404 was issued (S) which superseded PTC permit 047-00008 (issued May 7, 2000). This project was for the installation of an aerobic digester, a biogas/natural gas-fired hot water boiler (auxiliary boiler) and a biogas flare.
May 7, 2000	PTC permit 047-00008 was issued (S) which was for a facility name change from Avonmore West, Inc. to Glanbia Foods, Inc.
August 2, 1996	PTC permit 047-00008 was issued (S) which was for a facility expansion and facility-wide #2 distillate fuel oil combustion limit.
June 6, 1994	PTC permit 047-00008 was issued (S) which was for the installation of a 600 horsepower Cleaver Brooks boiler and added NSPS Subpart Dc emissions standards and removed performance testing requirements for the 600 horsepower Cleaver Brooks boiler.

2. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

2.1 Application Scope

This application modifies PTC No. P-2008.0065 by allowing biogas, generated from the anaerobic digester, to be combusted in full-time Boilers No. 2 and No. 3 for steam generation and to allow the combustion of biogas in auxiliary Boiler No.5 concurrently with the flare. The current PTC only allows biogas from the anaerobic digester to be combusted in either the auxiliary Boiler No.5 or the flare. In addition it does not allow simultaneous of biogas in the auxiliary Boiler No.5 and the flare.

In order to accomplish this modification, the facility is proposing to increase biogas production from the anaerobic digester from 433,823 scf/day to 505,000 scf/day, resulting in a net increase in biogas production of 71,177 scf/day.

The proposed increase in biogas production and allowance for operation flexibility will require a modification to four combustion sources at the facility: Boiler No.2, Boiler No.3, Boiler No.5, and the flare.

2.2 Application Chronology

July 16, 2008	DEQ Received Permit to Construct Application.
August 12, 2008	DEQ declared the application complete.
October 9, 2008	DEQ sent a draft PTC to the facility for review.
October XX, 2008	The project was proposed for a 30-day public comment period
October XX, 2008	$X,XXX PTC processing fee was received.
November XX, 2008	Final permit and statement of basis were issued.

3. TECHNICAL ANALYSIS

3.1 Emission Unit and Control Device

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emission Unit/ID No.	Emissions Unit Description	Control Device Description	Emissions Discharge Point ID No. and/or Description
Anaerobic Digester	Biogas production: 505,000 cubic feet per day	Four boilers and a flare	N/A
Biogas Flare/Flare	Manufacturer: Varec Biogas Model: No. 244 W Rated Heat Input: 13.68 MMBtu/hr Date of Installation: 2005	N/A	FLARE Exit height: 26.8 ft Exit diameter: 2.1 ft Exit flow rate: 14,062 acfm Exit temperature: 1,832 °F
Full-time Boiler 2/Blr. 2	Rated Heat Input: 25.1 MMBtu/hr Manufacturer: Cleaver Brooks Model No.: CB600-600 Serial No.: L-90943 Fuels: Natural gas/biogas/low-sulfur distillate fuel oil Date of Installation: July 1992	N/A	BOILER2 and BOIL2D Exit height: 36.0 ft Exit diameter: 2.0 ft Exit flow rate: 8,855 acfm Exit temperature: 390 °F
Full-time Boiler 3/Blr. 3	Rated Heat Input: 25.1 MMBtu/hr Manufacturer: Cleaver Brooks Model No.: CB600-600 Serial No.: L-79896 Fuels: Natural gas/biogas/low-sulfur distillate fuel oil Date of Installation: December 1996	N/A	BOILER3 and BOIL3D Exit height: 36.0 ft Exit diameter: 2.0 ft Exit flow rate: 8,855 acfm Exit temperature: 390 °F
Auxiliary Boiler 5/Blr.5	Manufacturer: Cleaver Brooks Model No.: CB700-400-30H Rated Heat Input: 16.73 MMBtu/hr Fuels: Natural gas/biogas Date of Installation: 2005	N/A	BOILER5 Exit height: 21.0 ft Exit diameter: 2.0 ft Exit flow rate: 6,966 acfm Exit temperature: 325 °F
Full-time Boiler 1/Blr. 1	Rated Heat Input: 26.4 MMBtu/hr Manufacturer: Cleaver Brooks Model No.: CB200-800-150 Fuels: Natural gas Date of Installation: November 14, 2006	N/A	BOILER1
Full-time Boiler 4/Blr. 4	Rated Heat Input: 25.1 MMBtu/hr Manufacturer: Cleaver Brooks Model No.: CB600-600 Serial No.: L-79895 Fuels: Natural gas Date of Installation: December 1999	N/A	BOILER4 Exit height: 36.0 ft Exit diameter: 2.0 ft Exit flow rate: 8,855 acfm Exit temperature: 390 °F
Lactose Production Line/Lactose Primary Dryer	Manufacturer: Relco Design Capacity: 11,500 lb/hr of total solids Max. Steam Usage Rate: 3,996 lb/hr	N/A	Exhaust stack DRYER1

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION (continued)

Emission Unit/ID No.	Emissions Unit Description	Control Device Description	Emissions Discharge Point ID No. and/or Description
Lactose Primary Dryer Baghouse	Manufacturer: Relco Type: Reverse pulse jet Number of Bags: 230 Bag Type: polyester Air to Cloth: 6.24 ft/min Control Efficiency: 99.99%	N/A, the baghouse is process equipment	Exhaust stack PDRYBH Exit height: 89.0 ft Exit diameter: 2.8 ft Exit flow rate: 18,752.5 acfm Exit temperature: 205 °F Type: Vertical
Lactose Production Line/Lactose Secondary Fluidized Bed Dryer	Manufacturer: Relco Design Capacity: 11,500 lb/hr of total solids Max. Steam Usage Rate: 3,996 lb/hr	N/A, the baghouse is process equipment	N/A
Fluidized Bed Dryer Baghouse	Baghouse: BH-05: Manufacturer: Relco Type: Reverse pulse jet Number of Bags: 180 Bag Type: polyester Air to Cloth: 6.17 ft/min Control Efficiency: 99.99%	N/A, the baghouse is process equipment	Exhaust stack FBEDBH Exit height: 89.0 ft Exit diameter: 2.5 ft Exit flow rate: 13,942.7 acfm Exit temperature: 163 °F Type: Vertical
Lactose Production Line/Lactose Receiving Baghouse	Manufacturer: NIRO Model #: 96LRT80 Style III Type: Reverse pulse jet Number of Bags: 75 Bag Type: polyester Air to Cloth: 4.53 ft/min Control Efficiency: 99.99%	N/A, the baghouse is process equipment	Exhaust stack LACBAG
Mill Process/Mill Receiving Baghouse (BH-05)	Baghouse: BH-05: Manufacturer: Relco Type: Reverse pulse jet Air to Cloth: 6.31 ft/min Control Efficiency: 99.99% Design Capacity: 11,500 lb/hr of total solids	N/A, the baghouse is process equipment	Exhaust stack MRECBH Exit height: 48.0 ft Exit diameter: 0.5 ft Exit flow rate: 440 acfm Exit temperature: 95 °F Type: Horizontal
Lactose Production Line/Powder Handling, Three Powder Bins	Bin 1 Mfg.: Niro Bin Capacity: 2,850 ft^3 Bin 2 Mfg.: Niro Bin Capacity: 2,850 ft^3 Bin 3 Mfg.: Niro Bin Capacity: 2,850 ft^3	Baghouse: BH-06: Manufacturer: Relco Type: Reverse pulse jet Bag Type: polyester Air to Cloth: 6.90 ft/min Control Efficiency: 99.99%	Exhaust stack PBINBH
Two Lactose Surge Hoppers	Two Lactose Surge Hopper Baghouses	Baghouse: BH-07: Manufacturer: Relco Type: Reverse pulse jet Bag Type: polyester Air to Cloth: 6.89 ft/min Control Efficiency: 99.99%	Exhaust stack LACHOPBH Exit height: 43.0 ft Exit diameter: 0.5 ft Exit flow rate: 440 acfm Exit temperature: 95 °F Type: Horizontal
WPC Bagging Line/WPC Surge Hopper	WPC Surge Hopper Baghouse	Baghouse: BH-08: Manufacturer: Donaldson Co., Inc. Type: Reverse pulse jet Bag Type: polyester Air to Cloth: 7.7 ft/min Grain Loading: 0.0044 gr/dscf	Exhaust stack WPCSRGBH
WPC Bagging Line/WPC Bagging Line	WPC Nuisance Baghouse	Baghouse: BH-09: Manufacturer: Donaldson Co., Inc. Type: Reverse pulse jet Bag Type: polyester Air to Cloth: 7.7 ft/min Grain Loading: 0.0044 gr/dscf	Exhaust stack WPC NUSB

3.2 Emissions Inventory

An emissions inventory for the cheese and whey processing plant was developed and submitted by the facility. The emission inventory is based on emission factors from various sections in AP-42 (including sections 1.3-1, 1.3-3, 1.4-2, and 13.5-1), the sources and emission controls descriptions summarized in the application, and the following operational limits: a maximum H_2S concentration of 1,799 ppmv for the biogas, a maximum daily amount of biogas produced of 505,000 scf, a maximum annual amount of distillate fuel oil combusted in boilers 2 and 3 of 387,258 gallons, and worst-case maximum operation of the equipment of 8,760 hours per year.

A summary of the uncontrolled and controlled point source emissions are shown in Tables 3.2, 3.3, and 3.4. The controlled emissions inventories are provided in Appendix A.

Table 3.2 POST PROJECT UNCONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS

Emissions Unit	PM_{10}	SO_2	NOx	CO	VOC	Lead
	T/yr	T/yr	T/yr	T/yr	T/yr	lb/quarter
Point Sources Affected by this Permitting Action						
Biogas Flare[1], Single Fuel Fired **(Biogas Combustion)**	0.43	24.39	4.07	22.16	3.77	0
Full-Time Boiler 2, Tri Fuel Fired **(Natural Gas Combustion)**	0.76	0.13	8.87	2.73	0.30	4.56E-05
Full-Time Boiler 2, Tri Fuel Fired **(Biogas Combustion)**	0.40	15.46	5.26	4.42	0.29	2.6E-05
Full-Time Boiler 2, Tri Fuel Fired **(Distillate Fuel Oil Combustion)**	0.32	0.69	1.94	0.48	0.05	1.22E-04
Full-Time Boiler 3, Tri Fuel Fired **(Natural Gas Combustion)**	0.76	0.13	8.87	2.73	0.30	4.56E-05
Full-Time Boiler 3, Tri Fuel Fired **(Biogas Combustion)**	0.40	15.46	5.26	4.42	0.29	2.6E-05
Full-Time Boiler 3, Tri Fuel Fired **(Distillate Fuel Oil Combustion)**	0.32	0.69	1.94	0.48	0.05	1.22E-04
Auxiliary Boiler 5[1], Duel Fuel Fired **(Natural Gas and Biogas Combustion)**	0.60	33.55	7.07	8.99	0.96	4.12E-5
Full-Time Boiler 1, Single Fuel Fired **(Natural Gas Combustion)**	0.83	0.07	10.95	9.20	0.60	5.47E-05
Full-Time Boiler 4, Single Fuel Fired **(Natural Gas Combustion)**	0.79	0.06	10.41	8.74	0.57	5.20E-05
WPC Dryer	0.29	0.02	3.81	3.20	0.21	1.91E-05
Backup Electrical Generator	0.06	0.29	1.82	0.48	0.05	5.13E-06
Heater 1	0.05	0.004	0.62	0.52	0.03	3.11E-06
Heater 2	0.19	0.01	2.44	2.05	0.13	1.22E-05
Heater 3	0.04	0.003	0.57	0.48	0.03	2.85E-06
Lactose Baghouse[1]	33,400	0	0	0	0	0
Lactose Primary Dryer Baghouse[1]	3,300	0	0	0	0	0
Lactose Fluidized Bed Dryer Baghouse[1]	2,300	0	0	0	0	0
Lactose Mill Receiving Baghouse[1]	3,300	0	0	0	0	0
Lactose Powder Bin Baghouse[1]	50,400	0	0	0	0	0
Lactose Surge Hoppers Baghouse[1]	77,100	0	0	0	0	0
WPC Surge Hopper Baghouse[2]	13	0	0	0	0	0
WPC Nuisance Baghouse[2]	50	0	0	0	0	0
Total, Point Sources	**169,869.0**	**31.1**	**69.8**	**60.3**	**6.7**	**5.77E-04**

1 Back calculated using controlled PE and the control efficiency of each baghouse (99.99% in this case).
2 Back calculated using controlled PE and the assumed control efficiency of each baghouse (99% in this case).

Table 3.3 PRE-PROJECT CONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS

Emissions Unit	PM_{10}		SO_2		NO_x		CO		VOC		Lead	
	lb/hr[1]	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Point Sources Affected by the Permitting Action												
Biogas Flare[1], Single Fuel-Fired **(Biogas Combustion)**	0.09	0.37	0	0	0.80	3.50	4.35	19.03	0.74	3.24	0	0
Full-Time Boiler 2, Dual Fuel-Fired **(Natural Gas Combustion)**	0.25	1.10	0.04	0.19	2.94	12.86	0.90	3.96	0.10	0.44	1.25E-05	5.47E-05
Full-Time Boiler 2, Dual Fuel-Fired **(Distillate Fuel Oil Combustion)**	0.59	0.32	1.27	0.69	3.59	1.94	0.90	0.48	0.10	0.05	2.26E-04	1.22E-04
Full-Time Boiler 3, Dual Fuel-Fired **(Natural Gas Combustion)**	0.25	1.10	0.04	0.19	2.94	12.86	0.90	3.96	0.10	0.44	1.19E-06	4.56E-05
Full-Time Boiler 3, Dual Fuel-Fired **(Distillate Fuel Oil Combustion)**	0.59	0.32	1.27	0.69	3.59	1.94	0.90	0.48	0.10	0.05	1.19E-05	5.20E-05
Auxiliary Boiler 5[1], Dual Fuel-Fired **(Natural Gas and Biogas Combustion)[2]**	0.12	0.52	6.59	28.86	1.39	6.08	1.76	7.73	0.19	0.82	5.56E-06	2.44E-05
Full-Time Boiler 1, Single Fuel Fired **(Natural Gas Combustion)**	0.19	0.83	0.01	0.07	2.50	10.95	2.10	9.20	0.14	0.60	1.25E-05	5.47E-05
Full-Time Boiler 4, Single Fuel Fired **(Natural Gas Combustion)**	0.18	0.79	0.01	0.06	2.38	10.41	2.00	8.74	0.13	0.57	1.19E-05	5.20E-05
WPC Dryer	0.07	0.29	0.01	0.02	0.87	3.81	0.73	3.20	0.05	0.21	4.35E-06	1.91E-05
Backup Electrical Generator	0.57	0.06	2.88	0.29	18.23	1.82	4.84	0.48	0.51	0.05	5.13E-05	5.13E-06
Heater 1	0.01	0.05	0.001	0.004	0.14	0.62	0.12	0.52	0.01	0.03	7.10E-07	3.11E-06
Heater 2	0.04	0.19	0.003	0.01	0.56	2.44	0.47	2.05	0.03	0.13	2.79E-06	1.22E-05
Heater 3	0.01	0.04	0.001	0.003	0.13	0.57	0.11	0.48	0.01	0.03	6.50E-07	2.85E-06
Lactose Baghouse	0.76	3.34	0	0	0	0	0	0	0	0	0	0
Lactose Primary Dryer Baghouse	0.08	0.33	0	0	0	0	0	0	0	0	0	0
Lactose Fluidized Bed Dryer Baghouse	0.05	0.23	0	0	0	0	0	0	0	0	0	0
Lactose Mill Receiving Baghouse	0.08	0.33	0	0	0	0	0	0	0	0	0	0
Lactose Powder Bin Baghouse	1.15	5.04	0	0	0	0	0	0	0	0	0	0
Lactose Surge Hoppers Baghouse	1.76	7.71	0	0	0	0	0	0	0	0	0	0
WPC Surge Hopper Baghouse	0.03	0.13	0	0	0	0	0	0	0	0	0	0
WPC Nuisance Baghouse	0.11	0.50	0	0	0	0	0	0	0	0	0	0
Pre-Project Totals	**6.98**	**23.59**	**12.12**	**31.08**	**40.06**	**69.80**	**20.08**	**60.31**	**2.21**	**6.66**	**5.69E-4**	**5.25E-4**

[1] Worst-case SO_2 emissions are emitted by Boiler 5 combusting biogas (flare is not operated concurrently with Boiler 5 when Boiler 5 is combusting biogas). Flare emissions are included in the facility combustion units total potential to emit for VOCs and CO.

[2] Biogas heat input is 11.75 MMBtu/hr and natural gas heat input is 5.0 MMBtu/hr for a total of 16.75 MMBtu/.hr for Boiler 5. Natural gas and biogas combustion emission rates must be added to quantify the potential emissions of Boiler 5.

Table 3.4 POST PROJECT CONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS

Emissions Unit	PM_{10}		SO_2		NO_x		CO		VOC		Lead	
	lb/hr[1]	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Point Sources Affected by the Permitting Action												
Biogas Flare, Single Fuel Fired **(Biogas Combustion)**	0.10	0.43	5.57	24.39	0.93	4.07	5.06	22.16	0.86	3.77	0	0
Full-Time Boiler 2, Tri Fuel Fired **(Natural Gas Combustion)**	0.17	0.76	0.03	0.13	2.02	8.87	0.62	2.73	0.07	0.30	1.19E-06	4.56E-05
Full-Time Boiler 2, Tri Fuel Fired **(Biogas Combustion)**	0.09	0.40	3.53	15.46	1.20	5.26	1.01	4.42	0.07	0.29	6.00E-06	2.6E-05
Full-Time Boiler 2, Tri Fuel Fired **(Distillate Fuel Oil Combustion)**	0.59	0.32	1.27	0.69	3.59	1.94	0.90	0.48	0.10	0.05	2.26E-04	1.22E-04
Full-Time Boiler 3, Tri Fuel Fired **(Natural Gas Combustion)**	0.17	0.76	0.03	0.13	2.02	8.87	0.62	2.73	0.07	0.30	1.19E-06	4.56E-05
Full-Time Boiler 3, Tri Fuel Fired **(Biogas Combustion)**	0.09	0.40	3.53	15.46	1.20	5.26	1.01	4.42	0.07	0.29	6.00E-06	2.6E-05
Full-Time Boiler 3, Tri Fuel Fired **(Distillate Fuel Oil Combustion)**	0.59	0.32	1.27	0.69	3.59	1.94	0.90	0.48	0.10	0.05	2.26E-04	1.22E-04
Auxiliary Boiler 5, Duel Fuel Fired **(Natural Gas and Biogas Combustion)**	0.14	0.60	7.66	33.55	1.61	7.07	2.05	8.99	0.22	0.96	9.4E-6	4.12E-5
Full-Time Boiler 1, Single Fuel Fired **(Natural Gas Combustion)**	0.19	0.83	0.01	0.07	2.50	10.95	2.10	9.20	0.14	0.60	1.25E-05	5.47E-05
Full-Time Boiler 4, Single Fuel Fired **(Natural Gas Combustion)**	0.18	0.79	0.01	0.06	2.38	10.41	2.00	8.74	0.13	0.57	1.19E-05	5.20E-05
WPC Dryer	0.07	0.29	0.01	0.02	0.87	3.81	0.73	3.20	0.05	0.21		
Backup Electrical Generator	0.57	0.06	2.88	0.29	18.23	1.82	4.84	0.48	0.51	0.05	5.13E-05	5.13E-06
Heater 1	0.01	0.05	0.001	0.004	0.14	0.62	0.12	0.52	0.01	0.03	7.10E-07	3.11E-06
Heater 2	0.04	0.19	0.003	0.01	0.56	2.44	0.47	2.05	0.03	0.13	2.79E-06	1.22E-05
Heater 3	0.01	0.04	0.001	0.003	0.13	0.57	0.11	0.48	0.01	0.03	6.50E-07	2.85E-06
Lactose Baghouse	0.76	3.34	0	0	0	0	0	0	0	0	0	0
Lactose Primary Dryer Baghouse	0.08	0.33	0	0	0	0	0	0	0	0	0	0
Lactose Fluidized Bed Dryer Baghouse	0.05	0.23	0	0	0	0	0	0	0	0	0	0
Lactose Mill Receiving Baghouse	0.08	0.33	0	0	0	0	0	0	0	0	0	0
Lactose Powder Bin Baghouse	1.15	5.04	0	0	0	0	0	0	0	0	0	0
Lactose Surge Hoppers Baghouse	1.76	7.71	0	0	0	0	0	0	0	0	0	0
WPC Surge Hopper Baghouse	0.03	0.13	0	0	0	0	0	0	0	0	0	0
WPC Nuisance Baghouse	0.11	0.50	0	0	0	0	0	0	0	0	0	0
Post Project Totals	**7.03**	**23.85**	**25.81**	**90.96**	**40.97**	**73.90**	**22.54**	**71.08**	**2.44**	**7.63**	**5.75E-4**	**5.58E-4**

Table 3.5 CHANGES IN CONTROLLED EMISSIONS ESTIMATES OF CRITERIA POLLUTANTS

	PM_{10}		SO_2		NO_x		CO		VOC		Lead	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Point Sources Affected by the Permitting Action												
Pre-Project Totals	6.98	23.59	12.12	31.08	40.06	69.80	20.08	60.31	2.21	7.01	5.69E-4	5.25E-4
Post Project Totals	7.03	23.85	25.81	90.96	40.97	73.90	22.54	71.08	2.44	7.63	5.75E-4	5.58E-4
Facility Total Change in Emissions	**0.05**	**0.26**	**13.69**	**59.88**	**0.91**	**4.10**	**2.46**	**10.77**	**0.23**	**0.62**	**6.0E-6**	**3.3E-5**

Table 3.6 CONTROLLED TAP AND HAP EMISSIONS SUMMARY

Non-Carcinogenic Toxic Air Pollutants	24-hour Average Emissions Rates for Units at the Facility[1] (lb/hr)	Non-Carcinogenic Screening Emission Level[3] (lb/hr)	Exceeds Screening Level? (Y/N)
Ammonia	2.01E-01	1.2	N
Barium	2.63E-04	0.033	N
Chromium (metal)	8.36E-05	0.033	N
Cobalt (metal, dust, and fume)	5.02E-06	0.0033	N
Copper (fume)	5.08E-05	0.013	N
Hexane	1.08E-01	12	N
Hydrogen sulfide	1.31E-01	0.933	N
Manganese (fume)	2.27E-05	0.067	N
Mercury (alkyl compounds)	1.55E-05	0.001	N
Molybdenum (soluble compounds)	6.57E-05	0.333	N
Naphthalene	3.64E-05	3.33	N
PAHs	6.54E-05	9.1E-05	N
Pentane	1.55E-01	118	N
Selenium	1.43E-06	0.013	N
Toluene	2.03E-04	25	N
Vanadium	1.37E-04	0.003	N
Zinc (metal)	1.73E-03	0.667	N
Acenaphthene	1.08E-07	N/A	N/A
Acenaphthylene	1.08E-07	N/A	N/A
Anthracene	1.43E-07	N/A	N/A
Benz(a)anthracene	1.08E-07	N/A	N/A
Benzo(b)fluoranthene	1.08E-07	N/A	N/A
Benzo(g,h,i)perylene	7.17E-08	N/A	N/A
Benzo(k)f1uoranthene	1.08E-07	N/A	N/A
Butane	1.25E-01	N/A	N/A
Chrysene	1.08E-07	N/A	N/A
Dibenzo(a,h)anthracene	7.17E-08	N/A	N/A
Dichlorobenzene	7.17E-05	N/A	N/A
7,12-Dimethylbenz(a)anthracene	9.56E-07	N/A	N/A
Ethane	1.85E-01	N/A	N/A
Fluoranthene	1.79E-07	N/A	N/A
Fluorene	1.67E-07	N/A	N/A
Indeno(1,2,3-cd)pyrene	1.08E-07	N/A	N/A
2-Methylnaphthalene	1.43E-06	N/A	N/A
Phenanathrene	1.02E-06	N/A	N/A
Propane	9.56E-02	N/A	N/A
Pyrene	2.99E-07	N/A	N/A

[1] – The facility modeled total emissions for all units located at the facility.

Table 3.7 CONTROLLED TAP AND HAP EMISSIONS SUMMARY

Carcinogenic Toxic Air Pollutants	Annual Average Emissions Rates for Units at the Facility[1] (lb/hr)	Carcinogenic Screening Emission Level[2] (lb/hr)	Exceeds Screening Level? (Y/N)
Arsenic	1.19E-05	1.5E-6	Y
Benzene	6.97E-04	8.0E-04	N
Benzo(a)pyrene	7.17E-08	2.0E-06	N
Beryllium	7.17E-07	2.8E-5	N
Cadmium	6.57E-05	3.7E-6	Y
Formaldehyde	6.44E-03	5.1E-04	Y
3-Methylchloranthrene	1.08E-07	2.5E-06	N
Nickel	1.25E-04	2.7E-05	Y

[1] – The facility modeled total emissions for all units located at the facility.

3.3 Ambient Air Quality Impact Analysis

Table 3.8 FULL IMPACT ANALYSIS RESULTS FOR CRITERIA POLLUTANT(S)

Pollutant	Averaging Period	Facility Ambient Impact (µg/m3)	Background Concentration (µg/m^3)	Total Ambient Concentration (µg/m^3)	NAAQS (µg/m^3)	Percent of NAAQS
PM_{10}	24-hour	1.68	N/A	N/A	150	N/A
	Annual	0.36	N/A	N/A	50	N/A
NO_2	Annual	18.79	32	50.79	100	50.8%
SO_2	3-hr	646.60	42	688.60	1,300	53.0%
	24-hr	218.11	26	244.11	365	66.9%
	Annual	22.97	8	30.97	80	38.7%
CO	1-hour	N/A	N/A	N/A	40,000	N/A
	8-hour	N/A	N/A	N/A	10,000	N/A
Pb	Quarterly	3.96E-05	0	N/A	1.5	N/A

N/A: The emissions rate is below the modeling threshold; modeling is not required in accordance with State of Idaho Air Quality Modeling Guidance DEQ Publication, December 2002, or alternative threshold approved by DEQ Modeling Coordinator.

Table 3.9 FULL IMPACT ANALYSIS RESULTS FOR TAP(S)

Pollutant	Average Period	Concentration (µg/m^3)	Regulatory AAC/AACC (µg/m^3)	Percent of Limit
Arsenic	Annual	0.0000200	0.00023	8.7%
Cadmium	Annual	0.000100	0.00056	17.9%
Formaldehyde	Annual	0.00485	0.077	6.3%
Nickel	Annual	0.000200	0.0042	4.8%

Note: AACs are in units of milligrams per meter cubed whereas AACCs are in units of micrograms per meter cubed. Convert AACs from milligrams per meter cubed to micrograms per meter cubed.

4. REGULATORY REVIEW

4.1 Attainment Designation (40 CFR 81.313)

The Glanbia Foods, Inc., Gooding facility is located in Gooding County (AQCR 63), which is designated as unclassifiable/attainment for $PM_{2.5}$, PM_{10}, SO_2, NO_x, and CO, for federal and state criteria air pollutants. Reference 40 CFR 81.313.

4.2 Permit to Construct (IDAPA 58.01.01.201)

IDAPA 58.01.01.201.....Permit to Construct Required

The facility's proposed project does not meet the permit to construct exemption criteria contained in Sections 220 through 223 of the Rules. Therefore, a PTC is required.

4.3 Tier II Operating Permit (IDAPA 58.01.01.401)

IDAPA 58.01.01.312.....Duty To Apply

The facility is not a Tier I source in accordance with IDAPA 58.01.01.006.113. Therefore, the requirements of IDAPA 58.01.01.312 do not apply.

4.4 Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

40 CFR 52.21…… .....Prevention of Significant Deterioration Of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source, not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore, in accordance with 40 CFR 52.21(a)(2), the PSD requirements do not apply.

4.5 Visible Emissions (IDAPA 58.01.01.625)

IDAPA 58.01.01.312…….....Visible Emissions

All of the permitted emissions units at this facility are subject to the State of Idaho visible emissions standard of 20% opacity. This requirement is assured by PTC conditions 2.6, 3.5, 4.4, and 5.4.

4.6 Fuel Burning Equipment-Particulate Matter, Standards for New Sources (IDAPA 58.01.01.676)

IDAPA 58.01.01.676…….....Fuel Burning Equipment-Particulate Matter, Standards for New Sources

Process Boilers 1, 2, 3, and 4 are subject to the particulate matter grain loading standard of 0.015 gr/dscf, corrected to 3% oxygen because all are allowed to combust gas. The auxiliary boiler 5 is also subject to this standard for both natural gas and biogas, which are both categorized as gaseous fuels. Based on the calculations submitted by the permittee, compliance with the grain loading standard has been demonstrated for Boilers 2, 3, and 5 using the "F-factor" calculation method contained in 40 CFR

60, Appendix A, Method 19. It is assumed that process Boilers 1 and 4 also comply with the grain loading standard for fuel burning equipment combusting natural gas.

Calculations provided by the permittee demonstrate that Boilers 2 and 3 comply with the grain loading standard of 0.050 gr/dscf, corrected to 3% oxygen, for liquid fuel (distillate fuel oil) by also using the "F-factor" calculation method.

This requirement is assured by PTC conditions 2.7 and 3.4.

4.7 Rules for Sulfur Content of Fuels-Distillate Fuel Oil (IDAPA 58.01.01.728)

IDAPA 58.01.01.728…….....Rules for Sulfur Content of Fuels-Distillate Fuel Oil

Boilers 2 and 3 are subject to the following limitations on sulfur content in distillate fuels:

> "No person shall sell, distribute, use or make available for use, any distillate fuel oil containing more than the following percentages of sulfur:
>
> 01. ASTM Grade 1. ASTM Grade 1 fuel oil - 0.3% by weight.
>
> 02. ASTM Grade 2. ASTM Grade 2 fuel oil - 0.5% by weight."

The permittee has requested an enforceable limit of 0.05% by weight of sulfur in the distillate fuel. This requirement is assured by PTC condition 2.14.

4.8 Rules for the Control of Odors (IDAPA 58.01.01.775-776)

IDAPA 58.01.01.775-776…… .....Rules for the Control of Odors

The facility is subject to the general restrictions for the control of odors from the Gooding facility. This requirement is assured by PTC condition 2.9.

4.9 Rules for Control of Incinerators-Emissions Limits (IDAPA 58.01.01.785)

IDAPA 58.01.01.785…….....Rules for Control of Incinerators-Emissions Limits

The flare is subject to the particulate matter emission standard for incineration. An "incinerator" is defined by IDAPA 58.01.01.006.51, which reads, in part:

> "For purposes of these rules, the destruction of any combustible liquid or gaseous material by burning in a flare stack shall be considered incineration."

The emission standard specified by IDAPA 58.01.01.786 requires that particulate matter emissions from the incinerator remain below 0.2 pounds per 100 pounds of refuse burned.

The permittee estimated particulate matter emissions to be 0.016 pounds per 100 pounds of refuse (methane from biogas in this case). Compliance was demonstrated by calculation of PM emissions. This requirement is assured by PTC condition 2.8.

4.10 PSD Classification (40 CFR 52.21)

40 CFR 52.21…… .....Prevention of Significant Deterioration Of Air Quality

The facility is not a major stationary source as defined in 40 CFR 52.21(b)(1), nor is it undergoing any physical change at a stationary source, not otherwise qualifying under paragraph 40 CFR 52.21(b)(1) as a major stationary source, that would constitute a major stationary source by itself as defined in 40 CFR 52. Therefore, in accordance with 40 CFR 52.21(a)(2), the PSD requirements do not apply.

4.11 NSPS Applicability (40 CFR 60)

40 CFR 60-Subpart Dc……Standards of Performance for Small Industrial –Commercial – Institutional Steam Generating Units

§ CFR 60.40c Applicability and Delegation of Authority

On July 13, 2005, EPA Region 10 made a determination on the permittee's alternative monitoring, recordkeeping, and reporting requirements for Boilers 1 through 5, for NSPS Subpart Dc. EPA Region 10 determined that the existing Process Boilers 2, 3, and 4 are subject to 40 CFR 60.4-Subpart Dc due to the construction dates and rated heat input capacities of each boiler. The installation date of Boiler 1 pre-dates NSPS-Subpart Dc applicability, and this emissions unit is not subject to any NSPS requirements.

Boiler 4 is permitted to combust natural gas only. Boilers 2 and 3 are permitted to combust natural gas, biogas, or low sulfur distillate fuel oil. Initial notification requirements apply to each of these boilers as an affected facility under 40 CFR 60-Subpart Dc, although initial notification should have been provided to EPA when the emissions units were originally constructed.

The permittee previously obtained a formal written determination of the monitoring and recordkeeping requirements for all five boilers at the Gooding facility, and this previous determination will be followed.

NSPS Subpart Dc monitoring and recordkeeping applies to the process boilers as follows:

- Boiler 1 is not subject to NSPS Subpart Dc because it was constructed prior to the applicability date of the NSPS. Boiler 1 is fired exclusively by natural gas. Monitoring and recordkeeping established by the State of Idaho will follow the guidelines set for the rest of the boilers.
- Boilers 2 and 3 operate on natural gas, biogas, or low sulfur distillate fuel oil having a sulfur content limit of 0.05 wt%. EPA previously approved monthly recordkeeping of both natural gas and distillate fuel oil but not biogas.

Boilers 2 and 3 will each have an individual fuel oil usage meter and a biogas meter. Monthly monitoring and recordkeeping frequency is required for fuel oil. Daily monitoring and recordkeeping frequency is required for biogas.

- Boiler 4 operates on natural gas exclusively and EPA has approved monthly recordkeeping of fuel usage.

Boilers 2, 3, and 4 were previously approved to share a single natural gas usage meter and the fuel usage will be monitored and recorded on a monthly basis. If more than one boiler is fired on natural gas during the monthly period, the permittee may prorate natural gas usage by dividing the heat input capacity of each boiler by the aggregated design heat input capacities of the boilers operated during that monthly period.

Boiler 5 is fired primarily on biogas generated by the anaerobic digester, and by natural gas as a backup fuel. Natural gas is also combusted at the same time as the biogas. EPA Region 10 denied approval of an alternative monitoring and recordkeeping of fuel consumption by Boiler 5 pending a determination that the biogas contains less than 0.5 wt % of sulfur with little variability in sulfur content. Monitoring and recordkeeping is required to be conducted daily in accordance with 40 CFR 60.48c(g).

Therefore, boilers 2 and 3 will each have an individual fuel oil usage meter and a biogas meter. Monthly monitoring and recordkeeping frequency is required for natural gas and fuel oil usage. Daily monitoring and recordkeeping frequency is required for biogas usage. These requirements are assured by PTC condition 2.18.

§ 60.41c.....Definitions.

The definitions of this section apply to the facility.

§ 60.42c Standard for sulfur dioxide (SO_2) emissions

Section (d) requires that on and after the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, no owner or operator of an affected facility that combusts oil shall cause to be discharged into the atmosphere from that affected facility any gases that contain SO_2 in excess of 215 ng/J (0.50 lb/MMBtu) heat input; or, as an alternative, no owner or operator of an affected facility that combusts oil shall combust oil in the affected facility that contains greater than 0.5 weight percent sulfur.

Boilers 2 and 3 are subject to the sulfur dioxide emission standard of 0.5 lb/MMBtu; or, alternatively, a limit of 0.5 weight percent sulfur in the fuel oil combusted. The facility has chosen to comply with the 0.5 weight percent sulfur content for the fuel oil. This requirement is assured by PTC condition 2.14.

Boilers 4 and 5 have rated heat input capacities of less than 30 MMBtu/hr and are operated on natural gas and biogas, respectively. These boilers are not subject to the sulfur dioxide emission standards specified by 40 CFR 60.42c.

§ 60.43c Standard for particulate matter (PM) emissions

This section applies to units that combusts coal or combusts mixtures of coal with other fuels and that have a heat input capacity of 8.7 MW (30 MMBtu/hr) or greater. All four of the boilers located at this facility subject to this subpart do not combust coal. This requirement is assured by PTC condition 2.12. Therefore, this section does not apply and no further discussion is required.

§ 60.44c Compliance and performance test methods and procedures for sulfur dioxide emissions

This section applies to units that have proposed to meet the 0.05 lb-SO_2/MMBtu limit of this subpart. This facility complies with the fuel sulfur percent by weight requirement. Therefore, the facility is required to comply with section (g).

Section (g) requires that for oil-fired affected facilities where the owner or operator seeks to demonstrate compliance with the fuel oil sulfur limits under §60.42c based on shipment fuel sampling, the initial performance test shall consist of sampling and analyzing the oil in the initial tank of oil to be fired in the steam generating unit to demonstrate that the oil contains 0.5 weight percent sulfur or less. Thereafter, the owner or operator of the affected facility shall sample the oil in the fuel tank after each new shipment of oil is received, as described under §60.46c(d)(2). This requirement is assured by PTC

condition 2.17.

§ 60.45c Compliance and Performance Test Methods and Procedures for Particulate Matter

The requirements of 40 CFR 60.45c do not apply because the requirements of 40 CFR 60.43c do not apply.

§ 60.48c Reporting and recordkeeping requirements

Section (e) requires that the owner or operator of each affected facility subject to the SO_2 emission limits, fuel oil sulfur limits, or percent reduction requirements under §60.42c shall keep records and submit reports as required under paragraph (d) of this section, including the following information, as applicable.

Calendar dates covered in the reporting period.

Each 30-day average SO_2 emission rate (ng/J or lb/MMBtu), or 30-day average sulfur content (weight percent), calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of corrective actions taken.

Each 30-day average percent of potential SO_2 emission rate calculated during the reporting period, ending with the last 30-day period; reasons for any noncompliance with the emission standards; and a description of the corrective actions taken.

Identification of any times when emissions data have been excluded from the calculation of average emission rates; justification for excluding data; and a description of corrective actions taken if data have been excluded for periods other than those during which coal or oil were not combusted in the steam generating unit.

Identification of the F factor used in calculations, method of determination, and type of fuel combusted.

These requirements are assured by PTC condition 2.17.

Section (g)(1) requires that except as provided under paragraphs (g)(2) and (g)(3) of this section, the owner or operator of each affected facility shall record and maintain records of the amount of each fuel combusted during each operating day.

As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility that combusts only natural gas, wood, fuels using fuel certification in §60.48c(f) to demonstrate compliance with the SO_2 standard, fuels not subject to an emissions standard (excluding opacity), or a mixture of these fuels may elect to record and maintain records of the amount of each fuel combusted during each calendar month.

As an alternative to meeting the requirements of paragraph (g)(1) of this section, the owner or operator of an affected facility or multiple affected facilities located on a contiguous property unit where the only fuels combusted in any steam generating unit (including steam generating units not subject to this subpart) at that property are natural gas, wood, distillate oil meeting the most current requirements in §60.42C to use fuel certification to demonstrate compliance with the SO2standard, and/or fuels, excluding coal and residual oil, not subject to an emissions standard (excluding opacity) may elect to

record and maintain records of the total amount of each steam generating unit fuel delivered to that property during each calendar month.

48g(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record.

These requirements are assured by PTC conditions 2.17 and 2.18.

4.12 NESHAP Applicability (40 CFR 61)

No NESHAPs apply to this facility.

4.13 MACT Applicability (40 CFR 63)

No MACTs apply to this facility because it is a minor source of HAPs.

4.14 CAM Applicability (40 CFR 64)

The facility is a minor facility for purposes of Title V, and is therefore not subject to CAM requirements.

4.15 Permit Conditions Review

This section describes the permit conditions for this initial permit or only those permit conditions that have been added, revised, modified or deleted as a result of this permitting action.

Old Table 1.1 from PTC No. P-2008.0065 has been rearranged to group like processes at the facility. Specifically, boilers 2 and 3 have been removed from section 3 and added to section 2. This was done since boilers 2 and 3 now combust biogas (in addition to previously permitted natural gas and distillate fuel) like boiler 5 does.

Old Permit Condition 2.1 from PTC No. P-2008.0065 has been updated to reflect the change in processes covered by this section of the permit.

Old Table 2.1 from PTC No. P-2008.0065 has been updated to reflect the current sources of emissions for this process.

Old Permit Condition 2.3 from PTC No. P-2008.0065 has been changed to reflect the change in emissions units covered by this section of the permit. In addition, the H_2S limits have been replaced by a maximum H_2S concentration for the biogas being combusted in the emissions units (see new PTC condition 2.5). The maximum H_2S concentration that demonstrates compliance with the previous permit limits is calculated as follows:

Assumptions:

MW of H_2S = 34.1 g/mole H_2S

The number 24.45 m^3/mole is the volume of a mole (gram molecular weight) of a gas or vapor when the pressure is at 1 atmosphere and at 77 ºF (25 ºC) .

With a maximum H_2S concentration of 1,799 ppmv (provided by the Applicant as a worst-case H_2S concentration of the biogas based upon three years of recordkeeping and stated in the permit, see PTC condition 2.5):

1,799 ppmv H_2S x 34.1 g/mole H_2S ÷ 24.45 m^3/mole = 0.002509 g-H_2S/m^3 = 2,509 mg-H_2S/m^3

The H_2S mass emissions rate (at maximum biogas production) is calculated as follows (converting mg-H_2S/m3 to lb-H_2S/hr):

Values used in the calculation:

Maximum biogas production = 505,000 scf/day (proposed by the Applicant and stated in the permit, see PTC condition 2.10)

H_2S Biogas concentration = 2,509 mg/m^3 (as calculated previously)

Conversions:

1 day = 24 hr
1 m^3 = 35.31 f^3
1 lb = 454,000 mg

Calculation of uncontrolled H_2S mass emissions rate:

Volume of gas combusted per hour = 505,000 scf/day ÷ 24 hr = 21,041.7 scf/hr

Converting flow rate to lb H_2S per hour = 21,041.7 scf/hr x 1m^3/35.31 ft^3 x 1 lb/454,000 mg x 2,509 mg/m^3 = 3.29 lb-H_2S/hr

Verification of controlled H_2S mass emissions rates from the flare and the boilers:

Old Permit Condition 2.12 from PTC No. P-2008.0065 lists a control efficiency of H_2S for the flare of 90% and the boiler of 98%. Therefore, H_2S emissions from each emissions unit are calculated as follows:

Flare emissions = 3.29 lb-H_2S/hr x (1 – 0.90) = 0.329 lb/hr = 7.89 lb-H_2S/day
This is less than the permit limit of 8.66 lb/day

Boiler emissions = 3.29 lb-H_2S/hr x (1 – 0.98) = 0.066 lb/hr = 1.579 lb-H_2S/day
This is less than the permit limit of 1.58 lb/day

Old Permit Condition 3.3.2 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.4. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2.

Old Permit Condition 2.4 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.6.

Old Permit Condition 2.5 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.7. In addition this Permit Condition has been modified to include the grain loading limit for liquid fuel combustion because boilers 2 and 3, which combust distillate fuel, have been added to this section of the permit.

Old Permit Condition 2.6 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.8.

Old Permit Condition 2.7 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.9.

Old Permit Condition 2.8 from PTC No. P-2008.0065 has been removed and the requirements are contained within new Permit Conditions 2.11 and 2.12.

New Permit Condition 2.10 has been added to limit daily biogas production from the anaerobic digester as proposed by the Applicant. Adding this condition, as well as new Permit Condition 2.5, allowed the removal of the H_2S limits contained within old Permit Condition 2.3 from PTC P-2008.0065.

New Permit Condition 2.11 has been added to specify which emissions units at the facility are allowed to combust biogas.

New Permit Condition 2.12 has been added to specify which fuels can be combusted in the flare, full-time boilers 2 and 3, and the auxiliary boiler 5 as proposed by the Applicant.

Old Permit Condition 3.6 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.13. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2.

Old Permit Condition 3.7 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.14. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2.

Old Permit Condition 2.9 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.15. In addition, the language of this permit condition has been updated to reflect that the flare has been operating at the facility since 2005.

Old Permit Condition 2.10 from PTC No. P-2008.0065 has been removed since the Applicant has provided modeling that takes into account concurrent combustion of biogas in the flare and the auxiliary boiler.

Old Permit Condition 3.9 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.16. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2.

Old Permit Condition 3.10 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.17. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2.

Old Permit Condition 2.11 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.18. In addition, this condition has been modified to include boilers 2 and 3. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2. This permit condition has been retained to maintain the integrity of the previously issued May 7, 2000 PTC

Old Permit Condition 2.12 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.19. In addition, the language of this permit condition has been updated to reflect that boilers 2 and 3 now combust biogas.

Old Permit Condition 2.13 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.20. In addition, the language of this permit condition has been updated to reflect that the flare has been operating at the facility since 2005.

Old Permit Condition 2.14 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.21. In addition, this condition has been updated to current standard DEQ language.

Old Permit Condition 3.1 from PTC No. P-2008.0065 has been updated to reflect the change in processes covered by this section of the permit.

Old Table 3.1 from PTC No. P-2008.0065 has been updated to reflect the current sources of emissions for this process.

Old Permit Condition 3.3.1 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 3.4. In addition this Permit Condition has been modified to exclude the grain loading limit for liquid fuel combustion because boilers 2 and 3, which combust distillate fuel, have been removed from section 3 and added to section 2.

As mentioned previously old Permit Condition 3.3.2 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.4. This was done to because boilers 2 and 3 have been removed from section 3 and added to section 2.

Old Permit Conditions 3.3.3 and 3.3.4 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 3.3. In addition, the emissions limits of these conditions have updated per the new emissions inventory submitted by the Applicant.

Old Permit Condition 3.4 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 3.5.

Old Permit Condition 3.5 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 3.6. In addition, this Permit Condition has been modified to exclude the fuel use requirements for boilers 2 and 3 because they have been removed from section 3 and added to section 2.

As mentioned previously old Permit Condition 3.6 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.13. This was done to because boilers 2 and 3 have been removed from section 3 and added to section 2.

As mentioned previously old Permit Condition 3.7 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.14. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2.

Old Permit Condition 3.8 from PTC No. P-2008.0065 has been removed. This was done because boilers are not subject to the open burning requirements of Idaho state law.

As mentioned previously old Permit Condition 3.9 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.16. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2.

As mentioned previously Permit Condition 3.10 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 2.17. This was done because boilers 2 and 3 have been removed from section 3 and added to section 2.

Old Permit Condition 3.11 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 3.7. This permit condition has been retained to maintain the integrity of the previously issued May 7, 2000 PTC

Old Permit Condition 4.52 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 4.6.

Old Permit Condition 4.6 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 4.7.

Old Permit Condition 4.7 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 4.8.

Old Permit Condition 4.8 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 4.9.

Old Permit Condition 4.9 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 4.10.

Old Permit Condition 5.5.2 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 5.6.

Old Permit Condition 5.6 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 5.7.

Old Permit Condition 5.7 from PTC No. P-2008.0065 has been renumbered to new Permit Condition 5.8.

Old Table 6.1 from PTC No. P-2008.0065 has been removed because the emissions limits for the various emissions units at the facility are already listed in each specific section of the permit.

5. PERMIT FEES

Table 5.1 lists the processing fee associated with this permitting action. The facility is subject to a processing fee of $5,000.00 because its permitted annual change in emissions is 75.63 T/yr. Refer to the chronology for fee receipt dates.

Table 5.1 PTC PROCESSING FEE TABLE

Emissions Inventory			
Pollutant	**Annual Emissions Increase (T/yr)**	**Annual Emissions Reduction (T/yr)**	**Annual Emissions Change (T/yr)**
PM_{10}	0.26	0	0.26
SO_2	59.88	0	59.88
NO_x	4.10	0	4.10
CO	10.77	0	10.77
VOC	0.62	0	0.62
HAPS[1]	0	0	0
Totals:	**75.63**	**0.00**	**75.63**
Fee Due	**$5,000.00 Based upon an annual increase in emissions of 10 T/yr to < 100 t/yr for a modification to an existing source**		

[1] – Metal HAPS emissions were accounted for in the facility's PM_{10} emissions and VOC HAPS were accounted for in the facility's VOC emissions.

6. PUBLIC COMMENT

A public comment period was made available to the public from **date** to **date**. During this time, comments **WERE / WERE NOT** submitted in response to DEQ's proposed action. IF COMMENTS WERE RECEIVED INCLUDE THE FOLLOWING TEXT A response to public comments document has been crafted by DEQ based on comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

Appendix A – Emissions Inventory

Flare PTE Emissions Calculations:

Table A.1 FLARE PRE-PROJECT HOURLY AND ANNUAL PTE FOR CRITERIA POLLUTANTS WHEN COMBUSTING BIOGAS

Emissions Unit	Rated Heat Input (MMBtu/hr)[1]	Annual Hours of Operation (hrs/yr)	Criteria Pollutant	Emissions Factors (lb/MMBtu)[2]	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Flare 1	11.75	8,760	PM_{10}	0.00725	0.09	0.37
			SO_2	0.407	4.78	20.95
			NO_x	0.068	0.80	3.50
			CO	0.3698	4.35	19.03
			VOC	0.063	0.74	3.24

[1] – Rated heat input is based upon the full heat input rating of the boiler and annual operation of 8,760 hrs/yr. Then the bio-gas gun limit of 12,000 scf/hr, with a higher heating value (HHV) of 650 Btu/scf, is taken into account with the remaining heat input from natural gas.

[2] – Based on AP-42 Table 1.4 (9/91) for PM_{10}, and AP-42 Table 13.5-1 (9/91) for NO_x, CO, and VOC and mass balance for SO_2 (conservatively assuming 100% of H_2S is converted to SO_2).

Table A.2 FLARE POST PROJECT HOURLY AND ANNUAL PTE FOR CRITERIA POLLUTANTS WHEN COMBUSTING BIOGAS

Emissions Unit	Rated Heat Input (MMBtu/hr)[1]	Annual Hours of Operation (hrs/yr)	Criteria Pollutant	Emissions Factors (lb/MMBtu)[2]	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Flare 1	13.68	8,760	PM_{10}	0.00725	0.10	0.43
			SO_2	0.407	5.57	24.39
			NO_x	0.068	0.93	4.07
			CO	0.3698	5.06	22.16
			VOC	0.063	0.86	3.77

[1] – Rated heat input is based upon the full heat input rating of the boiler and annual operation of 8,760 hrs/yr. Then the bio-gas gun limit of 12,000 scf/hr, with a higher heating value (HHV) of 650 Btu/scf, is taken into account with the remaining heat input from natural gas.

[2] – Based on AP-42 Table 1.4 (9/91) for PM_{10}, and AP-42 Table 13.5-1 (9/91) for NO_x, CO, and VOC and mass balance for SO_2 (conservatively assuming 100% of H_2S is converted to SO_2).

Boilers 2 and 3 PTE Emissions Calculations:

Table A.3 BOILERS 2 and 3 PRE-PROJECT HOURLY AND ANNUAL PTE FOR CRITERIA POLLUTANTS WHEN COMBUSTING NATURAL GAS

Emissions Unit	Rated Heat Input (MMBtu/hr)[1]	Annual Hours of Operation (hrs/yr)	Criteria Pollutant	Emissions Factors (lb/MMBtu)[2]	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Boilers 2 and 3	25.1	8,760	PM_{10}	0.010	0.25	1.10
			SO_2	0.0017	0.04	0.19
			NO_x	0.117	2.94	12.86
			CO	0.036	0.90	3.96
			VOC	0.004	0.10	0.44

[1] – Rated heat input is based upon the full heat input rating of the boiler and annual operation of 8,760 hrs/yr. Then the bio-gas gun limit of 12,000 scf/hr, with a higher heating value (HHV) of 650 Btu/scf, is taken into account with the remaining heat input from natural gas.

[2] – Based on AP-42 Table 1.4-2 (7/98) for PM_{10}, NO_x, CO, and VOC and mass balance for SO_2 (conservatively assuming 100% of H_2S is converted to SO_2).

Table A.4 BOILERS 2 and 3 POST PROJECT HOURLY AND ANNUAL PTE FOR CRITERIA POLLUTANTS WHEN COMBUSTING NATURAL GAS

Emissions Unit	Rated Heat Input (MMBtu/hr)[1]	Annual Hours of Operation (hrs/yr)	Criteria Pollutant	Emissions Factors (lb/MMBtu)[2]	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Boilers 2 and 3	17.3	8,760	PM_{10}	0.010	0.17	0.76
			SO_2	0.0017	0.03	0.13
			NO_x	0.117	2.02	8.87
			CO	0.036	0.62	2.73
			VOC	0.004	0.07	0.30

[1] – Rated heat input is based upon the full heat input rating of the boiler and annual operation of 8,760 hrs/yr. Then the bio-gas gun limit of 12,000 scf/hr, with a higher heating value (HHV) of 650 Btu/scf, is taken into account with the remaining heat input from natural gas.

[2] – Based on AP-42 Table 1.4-2 (7/98) for PM_{10}, NO_x, CO, and VOC and mass balance for SO_2 (conservatively assuming 100% of H_2S is converted to SO_2).

Table A.5 BOILERS 2 and 3 POST PROJECT HOURLY AND ANNUAL PTE FOR CRITERIA POLLUTANTS WHEN COMBUSTING BIO-GAS

Emissions Unit	Rated Heat Input[1] (MMscf/hr)	Annual Hours of Operation (hrs/yr)	Criteria Pollutant	Emissions Factors (lb/MMscf)[2]	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Boiler 2 and 3	0.01200	8,760	PM_{10}	7.6	0.09	0.40
			SO_2	294.2	3.53	15.46
			NO_x	100.0	1.20	5.26
			CO	84.0	1.01	4.42
			VOC	5.5	0.07	0.29

[1] – Rated heat input is based upon the bio-gas gun limit.

[2] – Based on AP-42 Table 1.4-2 (7/98) for PM_{10}, NO_x, CO, and VOC and mass balance for SO_2 (conservatively assuming 100% of H_2S is converted to SO_2).

Table A.6 BOILERS 2 and 3 PRE- AND POST PROJECT HOURLY AND ANNUAL PTE FOR CRITERIA POLLUTANTS WHEN COMBUSTING DISTILLATE FUEL OIL

Emissions Unit	Rated Heat Input[1] (gal/hr)	Annual Fuel Use Limit[2] (1,000 gal/yr)	Criteria Pollutant	Emissions Factors (lb/1,000 gal)[3]	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Boilers 2 and 3	179.3	193.629	PM_{10}	3.3	0.59	0.32
			SO_2	7.1	1.27	0.69
			NO_x	20	3.59	1.94
			CO	5	0.90	0.48
			VOC	0.556	0.10	0.05

[1] – Based on AP-42, Appendix A (9/85) which gives a HHV for distillate fuel oil of 140,000 Btu/gal.

[2] – It is assumed that annual fuel use for each boiler is the annual fuel use for both boiler 2 and 3 combined, as stated on the permit, prorated to each boiler. Since each boiler is rated at 25.1 MMBtu/hr, fuel is equal for each boiler (calculated as 387,258 gal/yr ÷ 2 = 193,629 gal/yr).

[3] – Based on AP-42 Table 1.3-1 (Boilers < 100 MMBtu/hr, distillate oil fired) (9/98) for PM_{10}, SO_2 (with a % by weight S content of 0.05), NO_x, and CO and AP-42 Table 1.3-3 (TOC, distillate oil fired) (9/98) for VOC.

Boiler 5 PTE Emissions Calculations:

Table A.7 BOILER 5 PRE-PROJECT HOURLY AND ANNUAL PTE FOR CRITERIA POLLUTANTS WHEN COMBUSTING BIO-GAS

Emissions Unit	Rated Heat Input (MMBtu/hr)	Annual Hours of Operation (hrs/yr)	Criteria Pollutant	Emissions Factors (lb/MMBtu)	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Boiler 5	11.766	8,760	PM_{10}	0.010	0.12	0.52
			SO_2	0.56	6.59	28.86
			NO_x	0.118	1.39	6.08
			CO	0.150	1.76	7.73
			VOC	0.016	0.19	0.82

[1] – Rated heat input is based upon the bio-gas gun limit.
[2] – Based on AP-42 Table 1.4-2 (7/98) for PM_{10}, NO_x, CO, and VOC and mass balance for SO_2 (conservatively assuming 100% of H_2S is converted to SO_2).

Table A.8 BOILER 5 POST PROJECT HOURLY AND ANNUAL PTE FOR CRITERIA POLLUTANTS WHEN COMBUSTING BIO-GAS

Emissions Unit	Rated Heat Input (MMBtu/hr)	Annual Hours of Operation (hrs/yr)	Criteria Pollutant	Emissions Factors (lb/MMBtu)	Hourly Emissions (lb/hr)	Annual Emissions (ton/yr)
Boiler 5	13.677	8,760	PM_{10}	0.010	0.14	0.60
			SO_2	0.560	7.66	33.55
			NO_x	0.118	1.61	7.07
			CO	0.150	2.05	8.99
			VOC	0.016	0.22	0.96

[1] – Rated heat input is based upon the bio-gas gun limit.
[2] – Based on AP-42 Table 1.4-2 (7/98) for PM_{10}, NO_x, CO, and VOC and mass balance for SO_2 (conservatively assuming 100% of H_2S is converted to SO_2).

Appendix B – Ambient Air Quality Impact Analysis

M E M O R A N D U M

DATE: October 14, 2008

TO: Darrin Pampaian, Air Quality Analyst, Air Program

FROM: Kevin Schilling, Stationary Source Modeling Coordinator, Air Program

PROJECT NUMBER: P-2008.0114

SUBJECT: Modeling Review for the Glanbia Foods, Inc., Permit to Construct Application for Modifications at their whey manufacturing Facility near Gooding, Idaho

1.0 SUMMARY

Glanbia Foods, Inc. (Glanbia) submitted a Permit to Construct (PTC) application to increase biogas usage in existing boilers at their whey manufacturing facility located near Gooding, Idaho. Air quality analyses involving atmospheric dispersion modeling of emissions associated with the proposed project were submitted to demonstrate the modification would not cause or significantly contribute to a violation of any ambient air quality standard (IDAPA 58.01.01.203.02 [Idaho Air Rules Section 203.02]). CH2M Hill, Inc. (CH2M), Glanbia's consultant, performed the submitted ambient air quality analyses.

A technical review of the submitted air quality analyses was conducted by DEQ. The submitted modeling analyses: 1) utilized appropriate methods and models; 2) was conducted using reasonably accurate or conservative model parameters and input data; 3) adhered to established DEQ guidelines for new source review dispersion modeling; 4) showed either a) that predicted pollutant concentrations from emissions associated with the proposed facility were below significant contribution levels (SCLs) or other applicable regulatory thresholds; or b) that predicted pollutant concentrations from emissions associated with the facility, when appropriately combined with background concentrations, were below applicable air quality standards at all receptor locations. Table 1 presents key assumptions and results that should be considered in the development of the permit.

Table 1. KEY ASSUMPTIONS USED IN MODELING ANALYSES

Criteria/Assumption/Result	Explanation/Consideration
Impacts from the emissions increase associated with the proposed modification were below significant contribution levels for PM_{10}	Facility-wide, full NAAQS impact analyses were not required for PM_{10}.
Cumulative NAAQS impact analyses were performed for sulfur dioxide and nitrogen dioxide	Maximum modeled impacts, when combined with background concentrations, were below NAAQS.

2.0 BACKGROUND INFORMATION

2.1 Applicable Air Quality Impact Limits and Modeling Requirements

This section identifies applicable ambient air quality limits and analyses used to demonstrate compliance.

2.1.1 Area Classification

The Glanbia facility is located in Gooding, Idaho. The area is designated as attainment or unclassifiable for all criteria pollutants.

2.1.2 Significant and Full NAAQS Impact Analyses

If estimated maximum pollutant impacts to ambient air from the emissions sources associated with the proposed modification exceed the significant contribution levels (SCLs) of Idaho Air Rules Section 006.102, then a cumulative NAAQS impact analysis is necessary to demonstrate compliance with National Ambient Air Quality Standards (NAAQS) and Idaho Air Rules Section 203.02. A cumulative NAAQS impact analysis for attainment area pollutants involves adding ambient impacts from facility-wide emissions, and emissions from any nearby co-contributing sources, to DEQ-approved background concentration values that are appropriate for the criteria pollutant/averaging-time at the facility location and the area of significant impact. The resulting maximum pollutant concentrations in ambient air are then compared to the NAAQS listed in Table 2. Table 2 also lists SCLs and specifies the modeled value that must be used for comparison to the NAAQS.

TABLE 2. APPLICABLE REGULATORY LIMITS

POLLUTANT	Averaging Period	Significant Contribution Levels[a] ($\mu g/m^3$)[b]	Regulatory Limit[c] ($\mu g/m^3$)	Modeled Value Used[d]
PM_{10}[e]	Annual[f]	1.0	50[g]	Maximum 1st highest[h]
	24-hour	5.0	150[i]	Maximum 6th highest[j]
$PM_{2.5}$[k]	Annual	Not established	15	Use PM_{10} as surrogate
	24-hour	Not established	35	Use PM_{10} as surrogate
Carbon monoxide (CO)	8-hour	500	10,000[l]	Maximum 2nd highest[h]
	1-hour	2,000	40,000[l]	Maximum 2nd highest[h]
Sulfur Dioxide (SO_2)	Annual	1.0	80[g]	Maximum 1st highest[h]
	24-hour	5	365[l]	Maximum 2nd highest[h]
	3-hour	25	1,300[l]	Maximum 2nd highest[h]
Nitrogen Dioxide (NO_2)	Annual	1.0	100[g]	Maximum 1st highest[h]
Lead (Pb)	Quarterly	NA	1.5[i]	Maximum 1st highest[h]

[a]Idaho Air Rules Section 006.102
[b]Micrograms per cubic meter
[c]Idaho Air Rules Section 577 for criteria pollutants
[d]The maximum 1st highest modeled value is always used for the significant impact analysis or analyses using the model SCREEN3
[e]Particulate matter with an aerodynamic diameter less than or equal to a nominal ten micrometers
[f]The annual PM_{10} standard was revoked in 2006. The standard is still listed because compliance with the annual $PM_{2.5}$ standard is demonstrated by a PM_{10} analysis that demonstrates compliance with the revoked PM_{10} standard.
[g]Never expected to be exceeded in any calendar year
[h]Concentration at any modeled receptor
[i]Never expected to be exceeded more than once in any calendar year
[j]Concentration at any modeled receptor when using five years of meteorological data
[k]Particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
[l]Not to be exceeded more than once per year

New source review requirements for assuring compliance with $PM_{2.5}$ standards have not yet been completed and promulgated into regulation. EPA has asserted through a policy memorandum that compliance with $PM_{2.5}$ standards will be assured through an air quality analysis for the corresponding PM_{10} standard. Although the PM_{10} annual standard was revoked in 2006, compliance with the revoked PM_{10} annual standard must be demonstrated as a surrogate to the annual $PM_{2.5}$ standard.

2.1.3 Toxic Air Pollutant Analyses

Emissions of toxic substances are generally addressed by Idaho Air Rules Section 161:

> *Any contaminant which is by its nature toxic to human or animal life or vegetation shall not be emitted in such quantities or concentrations as to alone, or in combination with other contaminants, injure or unreasonably affect human or animal life or vegetation.*

Permit requirements for toxic air pollutant emissions from new or modified sources are specifically addressed by Idaho Air Rules Section 203.03 and require the applicant to demonstrate to the satisfaction of DEQ the following:

> *Using the methods provided in Section 210, the emissions of toxic air pollutants from the stationary source or modification would not injure or unreasonably affect human or animal life or vegetation as required by Section 161. Compliance with all applicable toxic air pollutant carcinogenic increments and toxic air pollutant non-carcinogenic increments will also demonstrate preconstruction compliance with Section 161 with regards to the pollutants listed in Sections 585 and 586.*

Per Section 210, if the emissions increase associated with a new source or modification exceeds screening emission levels (ELs) of Idaho Air Rules Section 585 or 586, then the ambient impact of the emissions increase must be estimated. If ambient impacts are less than applicable Acceptable Ambient Concentrations (AACs) for non-carcinogens of Idaho Air Rules Section 585 and Acceptable Ambient Concentrations for Carcinogens (AACCs) of Idaho Air Rules Section 586, then compliance with TAP requirements has been demonstrated.

2.2 Background Concentrations

Background concentrations are used in the cumulative NAAQS impact analyses to account for impacts from sources not explicitly modeled. Table 3 lists appropriate background concentrations for the location of the proposed facility.

Background concentrations were revised for all areas of Idaho by DEQ in March 2003[1]. Background concentrations in areas where no monitoring data are available were based on monitoring data from areas with similar population density, meteorology, and emissions sources. Background concentrations were based on DEQ default values for small town/suburban areas.

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1 Hardy, Rick and Schilling, Kevin. *Background Concentrations for Use in New Source Review Dispersion Modeling*. Memorandum to Mary Anderson, March 14, 2003.

Table 3. BACKGROUND CONCENTRATIONS		
POLLUTANT	**Averaging Period**	**Background Concentration ($\mu g/m^3$)[a]**
PM_{10}[b]	24-hour	81
	Annual	27
Carbon monoxide (CO)	1-hour	10,200
	8-hour	3,400
Sulfur dioxide (SO_2)	3-hour	42
	24-hour	26
	Annual	8
Nitrogen dioxide (NO_2)	Annual	32
Lead (Pb)	Quarterly	0.03

a. Micrograms per cubic meter

b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers

3.0 MODELING IMPACT ASSESSMENT

3.1 Modeling Methodology

This section describes the modeling methods used by the applicant to demonstrate compliance with applicable air quality standards.

3.1.1 Overview of Analyses

Table 4 provides a brief description of parameters used in the submitted modeling analyses.

Table 4. MODELING PARAMETERS		
Parameter	**Description/Values**	**Documentation/Addition Description[a]**
General facility location	E 693 km, N 4,758 km	Located east of Gooding, Idaho, and surrounded by agricultural land
Model	AERMOD	AERMOD with the PRIME downwash algorithm, version 07026
Meteorological data	Minidoka/Boise 2000-2004	Minidoka surface data and Boise upper air data
Terrain	Considered	Receptor, building, and emissions source elevations were determined using Digital Elevation Model (DEM) files
Building downwash	Considered	The building profile input program (BPIP) was used
Receptor Grid	Grid 1	25-meter spacing along the property boundary out 25 meters
	Grid 2	100-meter spacing out to about 1,000 meters
	Grid 3	500-meter spacing out to about 5,000 meters
a. Values in parentheses are those used for DEQ verification analyses		

3.1.2 Modeling protocol and Methodology

The submitted air impact analyses were performed by CH2M. A modeling protocol was submitted to DEQ prior to receiving an earlier PTC application and DEQ provided conditional approval of the protocol to CH2M. Modeling was generally conducted using methods and data described in the protocol and the *State of Idaho Air Quality Modeling Guideline.*

The significant impact analyses involved modeling the emissions increase from four sources. Glanbia is currently permitted to burn biogas in Boiler No. 5 or burn biogas in the flare, but not to operate both on biogas concurrently. The proposed modification involves increasing allowable biogas use from 433,823 standard cubic feet per day (scf/day) to 505,000 scf/day, and to operate Boilers No. 2, No. 3, No. 5, and the flare simultaneously. Cumulative NAAQS impact analyses for NOx and SO_2, using facility-wide emissions and background concentrations, were required since modeled impacts from the significant impact analyses indicated significant contribution levels would be exceeded.

3.1.3 Model Selection

Idaho Air Rules Section 202.02 require that estimates of ambient concentrations be based on air quality models specified in 40 CFR 51, Appendix W (Guideline on Air Quality Models). The refined, steady state, multiple source, Gaussian dispersion model AERMOD was promulgated as the replacement model for ISCST3 in December 2005. EPA provided a 1-year transition period during which either ISCST3 or AERMOD could be used at the discretion of the permitting agency. AERMOD must be used for all air impact analyses, performed in support of air quality permitting, conducted after November 2006.

AERMOD retains the single straight line trajectory of ISCST3, but includes more advanced algorithms to assess turbulent mixing processes in the planetary boundary layer for both convective and stable stratified layers.

AERMOD offers the following improvements over ISCST3:

- Improved dispersion in the convective boundary layer and the stable boundary layer
- Improved plume rise and buoyancy calculations
- Improved treatment of terrain affects on dispersion
- New vertical profiles of wind, turbulence, and temperature

AERMOD was used in the submitted analyses.

3.1.4 Meteorological Data

Surface meteorological data from Minidoka, Idaho, and upper air data from Boise, Idaho, collected between 2000 and 2004, were processed through AERMET. AERMET is the meteorological data preprocessor for AERMOD. DEQ provided CH2M with the processed meteorological data.

Surface roughness, albedo, and Bowen ratio were evaluated on a sector-by-sector basis using land-use determinations within three kilometers of the meteorological monitoring site. USGS 1992 National Land Cover land-use data, with a 30-meter grid size, was used to assign landuse types. The USGS data were processed by Geomatrix Consultants using utility programs accompanying the CALPUFF modeling system. The MAKEGEO program associated with CALPUFF was then used to calculate a weighted average surface roughness length, albedo, and Bowen ratio. The sector-specific weighted geometric average was used for surface roughness while the weighted arithmetic average was used for albedo and Bowen ratio.

3.1.5 Terrain Effects

Terrain effects on dispersion were considered in the analyses. Receptor elevations and hill heights were obtained by CH2M using AERMAP and Digital Elevation Model (DEM) 7.5-minute files.

3.1.6 Facility Layout

The facility layout used in the modeling analyses, including the ambient air boundary, buildings, and emissions units, were checked against the layout provided in the application and aerial photographs of the site. The layout used in the model was sufficiently representative of the site layout.

3.1.7 Building Downwash

Downwash effects potentially caused by structures at the facility were accounted for in the dispersion modeling analyses. The Building Profile Input Program (BPIP) was used to calculate direction-specific building dimensions and Good Engineering Practice (GEP) stack height information from building dimensions/configurations and emissions release parameters for AERMOD.

3.1.8 Ambient Air Boundary

CH2M used the facility's property boundary as the ambient air boundary. DEQ assumed reasonable measures will be taken by the facility to preclude public access to the property.

3.1.9 Receptor Network

Table 4 describes the receptor grid used in the submitted analyses. The receptor grid met the minimum recommendations specified in the *State of Idaho Air Quality Modeling Guideline*. For these analyses, DEQ determined the receptor grid was adequate to reasonably resolve the maximum modeled concentrations to a degree that assures compliance with NAAQS at all ambient air locations.

3.2 Emission Rates

Emissions rates used in the modeling analyses for the proposed project were equal to those presented in other sections of the permit application or the DEQ Statement of Basis.

3.2.1 Criteria Pollutant Emissions Rates

Table 5 provides proposed increases in allowable criteria pollutant emissions rates that were used in the PM_{10} significant impact modeling analyses for both long-term and short-term averaging periods. The allowable emissions increase for carbon monoxide (CO) was below DEQ established thresholds that trigger the need for a specific air impact analysis.

Table 5. EMISSIONS RATES USED FOR FULL NAAQS IMPACT MODELING

Emissions Point	Description	Emissions Rates (lb/hr)		
		PM_{10}[a]	SO_2	NOx
BOILER2	Boiler 2	0.08	3.55	1.14
BOILER3	Boiler 3	0.08	3.55	1.14
BOILER5	Boiler 5	0.02	0.87	0.23
FLARE	Flare	0.01	5.57	0.13

[a] Particulate matter with an aerodynamic diameter less than or equal to a nominal ten micrometers

Table 6 provides facility-wide allowable emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NOx) used in the cumulative impact analyses.

Table 6. EMISSIONS RATES USED FOR CUMULATIVE NAAQS IMPACT MODELING			
Emissions Point	**Description**	**Emissions Rates (lb/hr)**	
		Sulfur Dioxide	**Oxides of Nitrogen**
BOILER1	Boiler 1	0.01	2.5
BOILER2	Boiler 2	3.56 1.27[a] (diesel)	3.22[a] 3.59 (diesel)
BOILER3	Boiler 3	3.56 1.27[a] (diesel)	3.22[a] 3.59 (diesel)
BOILER4	Boiler 4	0.01	2.38
BOILER5	Boiler 5	7.66	1.62
FLARE	Flare	5.57	0.93
DRYER1	WPC dryer	0.01 24-hour 0.00457 annual	0.87
GEN1	Generator	2.88 24-hour 0.066 annual	0.416
HEATERS	Heaters 1, 2, and 3	0.005 24-hour 0.00388 annual	0.829
PDRYBH	Primary dryer baghouse	0.0	0.0
FBEDBH	Fluidized bed baghouse	0.0	0.0
MRECBH	Mill receiving baghouse	0.0	0.0
PBINBH	Powder bin baghouse	0.0	0.0
LACHOPBH	Lactose surge hopper baghouse	0.0	0.0
WPCSRGBH	WPC surge hopper baghouse	0.0	0.0
WPCNUSBH	WPC nuisance baghouse	0.0	0.0
BH01	Existing lactose baghouse	0.0	0.0

[a] Value list for information only – not used in the modeling analyses. The other value listed was conservatively used in the modeling analyses since it was larger.

3.2.2 TAP Emissions Rates

Table 7 provides TAP emissions associated with the proposed modification. The table only includes those TAPs where total emissions exceeded emissions screening levels (ELs) of Idaho Air Rules Section 585 and 586.

Table 7. EMISSIONS RATES USED FOR TAPS IMPACT MODELING					
TAP	**Averaging Period**	**Emissions Rates (lb/hr)**			
		BOILER2	**BOILER3**	**BOILER5**	**FLARE**
Formaldehyde	Annual	1.38E-3	1.38E-3	2.22E-4	3.47E-3
Arsenic	Annual	5.68E-6	5.68E-6	5.93E-7	0.0
Cadmium	Annual	3.12E-5	3.12E-5	3.26E-6	0.0
Nickel	Annual	5.96E-5	5.96E-5	6.23E-6	0.0

3.3 Emission Release Parameters

Table 8 provides emissions release parameters used in the submitted analyses, including stack height, stack diameter, exhaust temperature, and exhaust velocity. All values appeared to be within reasonably expected ranges.

Parameters used for the flare were based on methods used in the SCREEN3 model.

The equivalent stack diameter is calculated by: $d = 9.88\ E\text{-}4(q_n)^{1/2}$

where q_n is the net heat release from the flare (cal/sec)

The net heat release q_n is given by: $q_n = (0.45)q$

where q is the gross heat release from the flare (cal/sec)

Submitted calculations indicate the gross heat release from the flare is 957,396 cal/sec, giving a net heat release of 430,828 cal/sec, and an effective diameter of 0.65 meters.

The effective stack height for a flare is calculated by: $H_a = H_s + [(4.56E\text{-}3)(q^{0.478})]$

where H_s is the physical flare height (meters) and q is the gross heat release from the flare (cal/sec)

Given a flare height of 4.87 meters, the effective height is calculated at 8.17 meters.

Table 8. EMISSIONS RELEASE PARAMETERS

Release Point/Location	***Source Type***	***Stack Height (m)[a]***	***Modeled Diameter (m)***	***Stack Gas Temp. (K)[b]***	***Stack Gas Flow Velocity (m/sec)[c]***
BOILER1	POINT	9.45	0.61	450	12.9
BOILER2	POINT	11.0	0.61	472	14.3
BOILER3	POINT	11.0	0.61	472	14.3
BOILER4	POINT	9.45	0.76	472	14.3
BOILER5	POINT	6.40	0.61	436	11.3
FLARE	POINT	8.17	0.65	1273	20.0
DRYER1	POINT	25.6	1.00	347	23.6
GEN1	POINT	4.27	0.41	750	51.5
Volume Sources					
Release Point/Location	*Source Type*	**Release Height (m)**	**Initial Horizontal Dispersion Coefficient σ_{y0} (m)**	**Initial Vertical Dispersion Coefficient σ_{z0} (m)**	
HEATERS	Volume	27.4	0.31	22.0	

[a] Meters
[b] Kelvin
[c] Meters per second

3.4 Results for Full NAAQS Impact Analyses

CH2M performed significant impact analyses for net emissions associated with the proposed modification, and results are shown in Table 9. Maximum impacts of PM_{10} were below significant contribution levels for both the 24-hour and annual averaging periods, and a full impact analysis was not necessary to demonstrate compliance. Impacts of sulfur dioxide (SO_2) and nitrogen dioxide (NO_2) were both above significant contribution levels; therefore, cumulative NAAQS impact analyses were required to demonstrate compliance with NAAQS.

Results of the cumulative NAAQS impact analyses are provided in Table 10. DEQ reviewed model output files submitted with the application for accuracy and use of appropriate input parameters. DEQ did not rerun the model to verify results.

Table 9. SIGNIFICANT IMPACT ANALYSES				
Pollutant	**Averaging Period**	**Maximum Modeled Concentration ($\mu g/m^3$)[a]**	**Significant Impact Level ($\mu g/m^3$)**	**Full Impact Analysis Required**
PM_{10}[b]	24-hour	1.68	5.0	No
	Annual	0.36	1.0	No
Sulfur Dioxide (SO_2)	3-hour	472.36	25	Yes
	24-hour	158.82	5	Yes
	Annual	12.83	1.0	Yes
Nitrogen Dioxide (NO_2)	Annual	4.03	1.0	Yes

a. Micrograms per cubic meter

b. Particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers

Table 10. RESULTS FOR CUMULATIVE IMPACT ANALYSES						
Pollutant	**Averaging Period**	**Modeled Concentration ($\mu g/m^3$)[a]**	**Background Concentration ($\mu g/m^3$)**	**Total Impact ($\mu g/m^3$)**	**NAAQS[b] ($\mu g/m^3$)**	**Comply with NAAQS**
Sulfur Dioxide (SO_2)	3-hour	649.6	42	691.6	1,300	Yes
	24-hour	218.1	26	244.1	365	Yes
	Annual	23.0	8	31.0	80	Yes
Nitrogen Dioxide (NO_2)	Annual	18.8	32	50.8	100	Yes

[a] Micrograms per cubic meter. Vales in parentheses are those generated through DEQ verification analyses

[b] Defined in Idaho Air Rules Section 577

3.5 Results for TAPs Analyses

CH2M performed TAPs impact analyses to evaluate compliance with applicable increments for those TAPs having emissions above screening levels (ELs) of Idaho Air Rules Section 585 and 586. Results of the TAPs impact analyses are provided in Table 11. The submitted application did not include model output files for arsenic. DEQ used the submitted model input files and reran the arsenic analysis to generate the results listed in Table 11.

Table 11. RESULTS FOR TAP IMPACT ANALYSES			
Pollutant	**Averaging Period**	**Modeled Impact ($\mu g/m^3$)[a]**	**AAC/AACC[b] ($\mu g/m^3$)**
Formaldehyde	Annual	4.85E-3	7.7E-2
Arsenic	Annual	2E-5[c]	2.3E-4
Cadmium	Annual	1.0E-4	5.6E-4
Nickel	Annual	2.0E-4	4.2E-3

[a] Micrograms per cubic meter.

[b] Defined in Idaho Air Rules Section 585 and 586

[c] Value from DEQ analysis

4.0 CONCLUSIONS

The ambient air impact analyses demonstrated to DEQ's satisfaction that emissions from the facility will not cause or significantly contribute to a violation of any air quality standard.

Appendix C – Facility Comments

No comments were received from the facility.